Commonwealth of Kentucky
Division for Air Quality

PERMIT STATEMENT OF BASIS

PROPOSED/FINAL TITLE V NO. V-05-057
THE SOMERSET REFINERY, INC.
SOMERSET, KY
August 18, 2006
RALPH GOSNEY, P.E., REVIEWER

SOURCE I.D. #:	21-199-00010
SOURCE A.I. #:	3842
ACTIVITY #:	APE20040003

SOURCE DESCRIPTION:

The Somerset Refinery (Somerset) is a petroleum refinery facility (SIC code 2911) which processes crude oil purchased from wells in Kentucky and Tennessee. The purchased crude oil is delivered by truck to the facility, as there are no pipeline, rail, or water deliveries to the facility. Somerset has a listed feed capacity of 5,500 barrels per day of operation. The purchased crude oil is segregated into high and low sulfur categories and stored in segregated oil feed tanks. The crude is processed in batches to produce low sulfur Diesel and No. 6 Fuel Oil. The crude contains suspended salt water that is removed and returned to an injection well for disposal. The raw gasoline is further processed by removing the sulfur and then increasing the aromatic content for octane enhancement. Various additives and dyes are added to most of the fuel products in order to comply with sales specifications and regulatory requirements.

During normal operations, the crude oil is fed through heat exchangers, salt drums, a hot oil tower, furnaces, and then into a crude fractionation tower. Heat is exchanged from the products to the crude oil in the heat exchangers. This step helps to reduce the load on the two furnaces that heat the crude to a temperature of approximately 720 degrees F. Crude oil is flashed in a small tower to produce No. 6 oil (black oil) from the bottom of the tower which is then stored in one of the black oil tanks. The vapors pass to the crude fractionation tower where both raw and finished products are drawn off. The products from this tower from top to bottom are Raw Gasoline, Kerosene, Diesel, and Heavy Gas Oil (HGO). The finished Diesel and HGO are directed to day tanks where they are examined to ensure that they meet with the specifications. They are then transferred to the finished storage area. The products can then be shipped from this area. The Raw Gasoline and Kerosene are sent to other units for further processing prior to sale.

Both the Raw Gasoline and Kerosene are hydrotreated in order to remove the sulfur containing compounds. This is accomplished by contacting the hydrocarbon with hydrogen over a Co-Mo catalyst where sulfur is converted to hydrogen sulfide for removal of gas. Hydrogen that is needed in this step is obtained from excess hydrogen produced in the Platinum Reformer at the facility. Raw gas from the intermediate storage passes through filters, exchangers, furnaces, a catalyst bed, and finally a high pressure drum with a tower to separate the gases from the liquid product. Gas in the overhead of the drums and towers comprises of hydrogen sulfide and other light hydrocarbon gases. This gas is processed through the Sodium hydrosulfide (NaHS) Unit where sulfur is removed. NaHS is produced as a byproduct for sale.

Raw Gasoline, called Naphtha at this point, is processed through the Platinum Reformer to increase the octane rating of the gasoline from approximately 78 octane to 83 blending stock. This is accomplished in a three-stage unit that increases the high octane aromatic content through dehydrogenation and recombination of the hydrocarbons. Following filtration and heat exchange, the liquid is pumped with special Rota-Jet pumps to raise the pressure to over 500 psig where the stream is combined with the recycled hydrogen stream from the high pressure drum in the unit. The combined stream is then heated to over 875 degrees F and fed successively through three reactors, furnaces and finally to the high pressure drum and separation tower (stabilizer). This final tower adjusts the Reed Vapor Pressure (RVP) to an allowable level by removal of butane and other light ends. The final product, blend stock, is sent to a day tank (191, 192, 193, or 194) where tests are performed to check specifications prior to transfer to the final sale tank.

All furnaces at the facility use gas fuels, and there is no liquid or solid used for fuel purposes. Fuel gas used at the facility comes from four sources and enters a common fuel system from which all furnaces and the steam boilers draw fuel. The high sulfur gas streams from the Crude Unit and the Hydrotreaters are processed through the NaHS unit to remove sulfur prior to entering the common fuel system. The fuel gas is typically high in hydrogen and burns clean with very little opacity. A continuous Emissions Monitor (CEM) on the common fuel system is used to monitor the sulfur content. A sulfur content of less than 0.1 gr/dcf is required to be maintained. The gas produced in the refinery is normally adequate for all fuel needs within the facility. In the event that additional fuel gas is needed, it is purchased from the local utility company. Excess fuel gas, if any, is directed to the flare.

The flare at the facility is used to provide a safe means to dispose of excess gas generated during normal operations, startups, shutdown, and emergencies. The flare consists of a six-inch burner tip with a forced air stream to insure adequate primary and secondary air to prevent excess opacity. A thermocouple is installed to allow operations to insure that a flame is present at all times.

The plant boiler provides steam for the plant as a utility and assists in fire fighting, startup of units, purging the units of air, regeneration, and general cleaning uses. The facility is also equipped with a 0.5 MW diesel emergency generator that can provide electricity when there is a power failure of the Kentucky Utilities power supply.

The refinery consists of the following permitted emission units and pollution control devices:

(a) One (1) refinery fuel gas fired 400 HP Continental Boiler, identified as EP01 and installed in 1997, with a maximum heat input capacity of 13.4 mmBtu/hr, equipped with low-NOx burners and exhausting to one (1) stack S1;

(b) One (1) refinery fuel gas fired Crude Distillation Heater, identified as EP02 and installed in 1974, with a maximum heat input capacity of 13.7 mmBtu/hr, equipped with low-NOx burners and exhausting to one (1) stack S2;

(c) One (1) flare, rated at a maximum capacity of 20.25 mmBtu/hr, identified as EP04, used to dispose of excess gas generated during normal operations, startups, shutdown and emergencies, and exhausting through stack S4;

(d) One (1) refinery fuel gas fired Crude Distillation Heater, identified as EP21 and installed in 1980, with a maximum heat input capacity of 10.0 mmBtu/hr, equipped with low-NOx burners and exhausting to one (1) stack S21;

(e) One (1) refinery fuel gas fired Gasoline Hydrotreater Heater, identified as EP22 and installed in 1987, with a maximum heat input capacity of 6.0 mmBtu/hr, equipped with low-NOx burners and exhausting to one (1) stack S22;

(f) One (1) refinery fuel gas fired Catalytic Reforming Heater, identified as EP23 and installed in 1975, with a maximum heat input capacity of 5.0 mmBtu/hr, equipped with low-NOx burners and exhausting to one (1) stack S23;

(g) One (1) refinery fuel gas fired Catalytic Reforming Heater, identified as EP24 and installed in 1975, with a maximum heat input capacity of 3.0 mmBtu/hr, equipped with low-NOx burners and exhausting to one (1) stack S24;

(h) One (1) refinery fuel gas fired Catalytic Reforming Heater, identified as EP25 and installed in 1975, with a maximum heat input capacity of 1.3 mmBtu/hr, equipped with low-NOx burners and exhausting to one (1) stack S25;

(i) One (1) refinery fuel gas fired Kerosene Hydrotreater Heater, identified as EP26 and installed in 1983, with a maximum heat input capacity of 2.0 mmBtu/hr, equipped with low-NOx burners and exhausting to one (1) stack S26;

(j) One (1) Crude Oil Distillation Column, identified as EP35 and installed in 1940, with a maximum capacity of 5,500 barrels per day, and producing naphtha, kerosene, diesel, heavy gas oil (HGO) and no. 6 oil. All emissions from this unit are hard piped to EP02 and EP21;

(k) One (1) Naphtha Hydrotreater, identified as EP36 and installed in 1956, with a maximum capacity of 1,540 barrels per day, and producing low sulfur naphtha. All emissions from this unit are hard piped to EP22;

(l) One (1) Naphtha Reformer, identified as EP37 and installed in 1956, with a maximum capacity of 1,540 barrels per day, and producing gasoline blending stock and gasoline. All emissions from this unit are hard piped to EP23, EP24 and EP25;

(m) One (1) Sulfur Removal Unit, consisting of a Sodium Hydro Sulfide (NaHS) Unit and Sulfa Treat Columns (backup sulfur removal system), identified as EP55 and installed in 1997, with a maximum processing capacity of 250 cubic feet per minute high sulfur fuel gas (240 ppm H2S) and 0.2 gallons per minute sodium hydroxide (25%) solution (aqueous), and producing low sulfur plant fuel gas (less than 0.1 gr/dcf) and sodium hydro sulfide; and one (1) vertical fixed roof storage tank storing sodium hydro sulfide with storage capacity of 9,219 gallons, identified as Tank 200.

(n) One (1) Tank Truck/Trailer Loading Rack, identified as EP06, consisting of the following:

(06a) Bottom Lading Rack constructed in July, 1993, consisting of two loading lanes with a total of six bottom loading arms, and equipped with John Zink Carbon Adsorption/Absorption Vapor Recovery Unit (VRU) controlling VOC and HAP emissions. Loading Diesel, Gasoline, Kerosene, and Naphtha.

(06b) Splash Loading Rack constructed in 1950's, consisting of two loading lanes. Loading Crude oil, Waste oil, No. 6 fuel oil, Heavy gas oil, and Naphtha.

(o) The following storage tanks:

Emission Point (Tank ID #)	Description	Product Stored (vapor pressure)	Installation Date	Storage Capacity (Gallons)
14 (167)	Vertical Fixed Dome Roof Tank	#2 fuel oil (< 1.0 psia)	1950	269,942.65
14 (168)	Vertical Fixed Dome Roof Tank	#2 fuel oil (< 1.0 psia)	1950	269,942.65
10 (160)	Internal Floating Roof Tank with primary seal (Vapor-mounted)	Gasoline RVP 9 (11 psia)	1950	128,345
10 (161)	Internal Floating Roof Tank with primary seal (Vapor-mounted)	Gasoline RVP 9 (11 psia)	1950	128,345
11 (153)	Vertical Fixed Dome Roof Tank	Slop oil (4.0 psia)	1960	39,127
15 (157)	Vertical Fixed Dome Roof Tank	Used Oil (<0.1 psia)	1950	34,834
15 (158)	Vertical Fixed Dome Roof Tank	Used Oil (<0.1 psia)	1950	23,261
19 (181)	Vertical Fixed Dome Roof Tank with vapor resilient seal and equipped with vapor recovery unit	Ethanol (4.0 psia)	1969	51,088

Emission Point (Tank ID #)	Description	Product Stored (vapor pressure)	Installation Date	Storage Capacity (Gallons)
07 (182)	Vertical Fixed Dome Roof Tank with vapor resilient seal and equipped with vapor recovery unit	Gasoline (12.0 psia)	1969	50,285
07 (191)	Vertical Fixed Dome Roof Tank with vapor resilient seal and equipped with vapor recovery unit	Gasoline (12.0 psia)	1969	66,643
07 (192)	Vertical Fixed Dome Roof Tank with vapor resilient seal and equipped with vapor recovery unit	Gasoline (9.0 psia)	1969	66,222
07 (193)	Vertical Fixed Dome Roof Tank with vapor resilient seal and equipped with vapor recovery unit	Gasoline (11.0 psia)	1969	67,432
07 (194)	Vertical Fixed Dome Roof Tank with vapor resilient seal and equipped with vapor recovery unit	Gasoline (11.0 psia)	1969	66,431
09 (186)	Internal Floating Roof Tank with primary seal (Vapor-mounted) and secondary seal (Rim-mounted)	Raw Gasoline (Naphtha) (<9.0 psia)	1973	303,549
14 (179a)	Vertical Fixed Dome Roof Tank	#2 fuel oil (< 1.0 psia)	1975	25,592.40
14 (179b)	Vertical Fixed Dome Roof Tank	#2 fuel oil (< 1.0 psia)	1975	25,592.40
14 (179c)	Vertical Fixed Dome Roof Tank	#2 fuel oil (< 1.0 psia)	1975	25,592.40
08 (190)	Internal Floating Roof Tank with primary seal (Vapor-mounted) and secondary seal (Rim-mounted)	Crude oil RVP 5 (2.69 psia)	1975	1,066,741
31 (196)	Internal Floating Roof Tank with primary seal (Vapor-mounted) and secondary seal (Rim-mounted)	Crude oil RVP 5 (2.69 psia)	1975	426,232
14 (173)	Vertical Fixed Dome Roof Tank	Kerosene (<1.0 psia)	1975	25,592.40
13 (195)	Vertical Fixed Dome Roof Tank	Kerosene (<1.0 psia)	1975	290,536.01

Emission Point (Tank ID #)	Description	Product Stored (vapor pressure)	Installation Date	Storage Capacity (Gallons)
16 (183)	Vertical Fixed Dome Roof Tank	Heavy gas oil (<0.1 psia)	1975	289,820.40
13 (184)	Internal Floating Roof Tank with primary seal (Vapor-mounted) and secondary seal (Rim-mounted)	Heavy gas oil (<0.1 psia)	1975	292,151
16 (187)	Internal Floating Roof Tank with primary seal (Vapor-mounted) and secondary seal (Rim-mounted)	Heavy gas oil (<0.1 psia)	1975	420,604.61
30 (197)	Internal Floating Roof Tank with primary seal (Vapor-mounted) and secondary seal (Rim-mounted)	Naphtha (9.0 psia)	1975	215,964
16 (188)	Vertical Fixed Dome Roof Tank	#6 Oil (<0.1 psia)	1975	441,220
16 (189)	Vertical Fixed Dome Roof Tank	#6 Oil (<0.1 psia)	1975	1,115,079
17 (198)	Horizontal Fixed Roof Tank	#2 fuel oil (<1.0 psia)	1982	7,700
17 (199)	Horizontal Fixed Roof Tank	#2 fuel oil (<1.0 psia)	1982	7,700
17 (201)	Vertical Fixed Dome Roof Tank	Used Oil (<0.1 psia)	1982	9,111
16 (180)	Vertical Fixed Dome Roof Tank	Used Oil (<0.1 psia)	1983	10,000
16 (180a)	Vertical Fixed Dome Roof Tank	Used Oil (<0.1 psia)	1983	8,754.06

(p) Pipeline equipment fugitive emissions consisting of the following:

Emission Point	Unit ID/Operation	Component (Count)
0A	(A1) Tank 152	Flanges (19) Valves (8)

	(A3) Crude Unloading Rack	Flanges (174) Valves (284) Pump Seals (20)
	(A4) Waste Unloading Rack	Flanges (27) Valves (69) Pump Seals (2)
	(A5) 87 Octane Line	Flanges (54)
	(A6) New Diesel Fugitives	Flanges (212)
05	Others	Flanges (569) Valves (820) Pump Seals (16) Connectors (283) Compressor Seals (10) Relief Valves (37) Open ended/ Drains (14)

The source also consists of the following insignificant activities, as defined in 401 KAR 52:020, Section 6:

1. Operators Testing Shack – Laboratory Facility
2. Steam Pad Emissions
3. Plant Maintenance – 3 Shutdowns per year
4. Dust from roads [401 KAR 63:010]
5. General painting of plant structures and equipment
6. Occasional machining in fabrication shop [401 KAR 59:010]
7. One (1) No. 2 fuel oil fired space heater in fabrication shop rated at 0.125 mmBtu/hr
8. Electrical backup generator
9. Truck maintenance runup
10. Gas powered plant equipment (i.e., welders, small motors, etc.) [401 KAR 59:010]
11. Tank 97 diesel treatment power service, Premium Diesel Kleen® Performance Improver 3341-04 (vapor pressure = 0.2 to 0.8 mm Hg @ 20^{o}C per manufacturer) [401 KAR 63:010]
12. Tank 96 Multifunction Gasoline Treatment DMA-582 (vapor pressure = high viscous solution) [401 KAR 63:010]
13. EP A2 - Two (2) cooling towers [Permit No. S-96-183]
14. One (1) 25,892.4 gallon vertical fixed roof tank identified as EP20, constructed in 1969 and storing Sodium Hydroxide.
15. Oil/water separator consisting of 1600 liter open rectangular pit and constructed in 1940.

16. Five (5) wastewater storage tanks identified as EP 18.

Existing Approvals:

1. Construction Permit No. C-84-157, issued on October 5th, 1984, for Emission Points 21 and 26.
2. Operating Permit No. O-84-124 (Revised), issued on February 13th, 1987, for Emission Points 01, 02, 04, 06 – 19, and 21 – 26.
3. Construction Permit No. C-87-178, issued on January 13th, 1988, for Emission Points 27 and 28. *These units have been dismanteled and removed from the facility and this permit is no longer applicable. The units have been removed from the facility's KYEIS.*
4. Construction Permit No. C-88-129, issued on July 25th, 1988, for Emission Points 30 and 31.
5. Construction Permit No. C-93-126, issued on September 7th, 1993, for Emission Point 06.
6. Construction Permit No. S-96-183, issued on May 6th, 1996 for Emission Points A2 – A6.
7. Construction Permit No. S-95-208 (Revision 2), issued on September 10th, 1997, for the Sulfur Removal Unit.
   Note: This permit did not establish an emission point (EP) identification number for this unit. As such, emission point number EP55 is established in this Title V permit for this unit.
8. Construction Permit No. S-96-224, issued on June 27th, 1996, for Emission Point 01.
9. Construction Permit No. S-97-087, issued on September 8th, 1997, for Tank 184A, Emission Point 13 (Tank 184A was identified as Tank 184 in Permit No. O-84-124 (Revised), this is the same tank).
10. Construction Permit No. S-00-082, issued on June 15th, 2000, for Emission Point 17.
11. Construction Permit No. S-00-094, issued on June 19th, 2000 for the emissions units associated with the manufacture of Racing Fuel and Fuel Additive.
   Note: The permittee notified DAQ on January 25th, 2002 and requested that this permit be cancelled since the project was abandoned. Therefore, this process and related permit requirements are not contained in the Title V permit.

Following emission units have been removed from operation or changed service:

1. Tank 110 for 'Barn Paint' is out of service. Barn Paint is no longer stored or utilized at the facility.
2. Tank 169 has been removed from service.
3. Tank 200 has been reassigned to the Sulfur Removal Unit under Permit S-95-208.
   Note: The permittee has requested that Tank 200, included in Permit No. O-84-124 (Revised) as EP17, be removed from the EP17 designation and be considered part of the Sulfur Removal Unit as a tank dedicated to that system. As such, tank 200 is included in Section B of the permit pertaining to the Sulfur Recovery Unit (EP55).
4. Six (6) gasoline storage tanks, identified as EP12, have been removed from operation and no longer exist at the facility.
5. Tank 151 has been taken out of service.
6. Tank 155 has been converted to a fuel gas pressure vessel.
7. Tank 202 has been converted to a wastewater storage tank.
8. Isomerization heater identified as EP27 and catalyst activation identified as EP28, both approved in Permit No. C-87-178, issued on January 13th, 1988, have been removed from operation and no longer exist at the facility.
9. Tanks 156 and 108 have been removed and Tank 169 is out of service.

Minor Permit Revision for an insignificant activity

During this permit review, the following new emission units have been approved for incorporation into this permit. These units meet the emissions criteria for an insignificant activity pursuant to 401 KAR 52:020, Section 6(a). This notwithstanding, the units do not meet the criteria of 401 KAR 52:020, Section 6(c) since they are subject to the requirements of 40 CFR 60.104 as discussed below. Therefore, these units are included in Section B of the permit pertaining to indirect heat exchangers.

(a) One (1) Vacuum Tower identified as EP56 and installed in 2006, with a maximum capacity of 9,625 gallons per hour, and producing petroleum distillates, gas oils, and other residues. The Vacuum Tower is equipped with a furnace with a maximum heat input rating of 2.6 mmBtu/hr, combusting refinery fuel gas and exhausting to one (1) stack S56. The permittee requested approval for this unit on July 28, 2005 as part of the application for this Title V operating permit.

(b) One (1) Modified Hydrotreater Catalyst Unit, identified as EP57 and installed in 2006, rated at maximum hourly capacity of 2,814 gallons per hour, and producing Low-Sulfur diesel fuel. The Modified Hydrotreater Catalyst Unit is equipped with a furnace with a maximum heat input rating of 5.0 mmBtu/hr, combusting refinery fuel gas and exhausting to one (1) stack S57. The permittee requested approval for this unit on July 28, 2005 as part of the application for this Title V operating permit.

(c) Two (2) refinery fuel gas fired indirect heat exchangers for Tank 187, installed in 2005 and identified as EP S187, each rated at 1.5 mmBtu/hr. The permittee requested approval for these units, as well as four other identical heaters, on March 20, 2000. During this review, however, the permittee withdrew their request for the four other identical heaters.

The potential to emit (as defined in 401 KAR 52:001, Section 1 (56)) of any nonhazardous regulated air pollutant is less than 100 tons per year, any single HAP is less than ten (10) tons per year, and the combination of HAPs is less than twenty-five (25) tons per year. Therefore, the source is a minor source pursuant to the provisions of 401 KAR 52:040. However, the permittee has decided to voluntarily apply for, and request issuance of, a Title V permit pursuant to 401 KAR 52:020. This permit is the first issue Title V operating permit for this source.

COMMENTS:

Type of control and efficiency:

The loading rack at the source is equipped with a John Zink Carbon Adsorption/Absorption Vapor Recovery Unit (VRU) controlling VOC and HAP emissions. The VRU system consists of a dual bed carbon absorption unit on the bottom loading rack that receives the vapors from trailers being loaded with the liquid product. The beds are cycled in order to regenerate one bed by vacuum while the other is in service. The regenerated vapors from the compressor are scrubbed and the recovered hydrocarbon vapors are returned to the finished product tank for sale. The stack from the bed that is in service has an IR detector that continuously monitors the emissions. The VRU system has a control efficiency of 99.9%.

Emission Calculations:

AP-42, Chapter 1.4, Tables 1.4-1, -2 and -3 were used to determine the refinery fuel gas combustion emissions, which closely resembles the natural gas, from the following emission units: 400 HP Continental Boiler (EP01), Crude Distillation Heater (EP02), Crude Distillation Heater (EP21), Gasoline Hydrotreater Heater (EP22), Catalytic Reforming Heater (EP23), Catalytic Reforming Heater (EP24), Catalytic Reforming Heater (EP25), Kerosene Hydrotreater Heater (EP26), Vacuum Tower (EP56), Modified Hydrotreater Catalyst Unit (EP57), and two (2) Indirect Heat Exchangers (S187)

AP-42, Chapter 13.5, Table 13.5-1 was used to determine the refinery fuel gas combustion emissions from the refinery flare identified as EP04.

Potential VOC emissions from the storage tanks were calculated using U.S. EPA TANKS4.09 program, with results provided by the permittee. Due to the business of the refinery, tanks are periodically changed-out, repaired, etc. that greatly varies the throughput for the tanks from time to time. Upon examining the TANKS4.09 output results and the varied throughput it was determined to calculate an emission factor for each tank. The tanks were then grouped by type and product. For each tank of the same product, the highest emission factor was selected to represent the product for the tank group. A maximum throughput for the distillery was determined based upon the maximum operational capacity of the refinery. This consisted of the maximum amount of crude that could be processed annually and also the data from the last 3 years of operation was examined to determine the maximum cut for each product. The maximum cut or production for the stream was multiplied by the emission factor to get the VOC emissions for each product stored in the tank group. Furthermore, the Hazardous Air Pollutant (HAP) speciation data provided by the source was applied to the total VOC emissions to determine the annual HAP emissions from the storage tanks.

Fugitive VOC emissions from equipment leaks were calculated based on the “Preferred and alternative methods for estimating fugitive emissions from equipment leaks”, Final Report, Volume II: Chapter 4, Table 4.4-4. These emissions were calculated for valves, flanges, connectors, pump seals, compressor seals, relief valves, and drains located throughout the refinery in gas and liquid services. Furthermore, HAP speciation data as provided by the permittee was applied to the total VOC emissions to determine the HAP emissions from the fugitive leaks. HAP emissions were determined for liquid service only, as the gas service contains negligible HAP amounts.

AP-42, Chapter 5, Table 5.1-2 was used to determine the fugitive VOC emissions from the oil/water separator and cooling tower. Related HAP emissions were calculated using the speciation data provided by the permittee.

AP-42, Chapter 5.2, Table 5.2-5 was used to determine the VOC emissions from the Loading Rack. HAP emissions were calculated using the speciation data provided by the permittee. VOC and HAP emissions from the loading rack are controlled by a Carbon bed with a control efficiency of 99.9%.

Basis for emission factors for each emission unit at the plant including the fugitive emissions from equipment leaks have been reviewed by KDAQ and seem to be correct for this type of operation. In addition, a comparison of source-wide emissions was also made to similar type of sources to make sure the emissions are representative of a similar size refinery. This comparison justified the emission levels from this type of plant and can be found in the Division file.

Please refer to the Pollutants of Concern (POC) table of this document for detailed emission calculations.

Applicable Regulations:

Storage Tanks

(a) 401 KAR 60:005, Sections 2 and 3(1)(o) incorporates by reference *40 CFR Part 60.110 to 60.113(Subpart K), "Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978"*

<u>*Emission Units Subject to 40 CFR 60, Subpart K:*</u>
Storage tanks identified as 186, 190, 195, 183, 188 and 189 are subject to the requirements of 40 CFR 60, Subpart K, because each tank has a capacity greater than 246,052 liters (65,000 gallons) and commenced construction or modification after June 11, 1973, and prior to May 19, 1978. Tank 190 stores crude oil and has a true vapor pressure greater than 1.0 psia. Tank 186 stores raw gasoline (naphtha) with vapor pressure greater than 1.0 psia. Tank 195 stores kerosene and tanks 195, 183, 188 and 189 each store heavy gas oil, and both of these liquid materials have a true vapor pressure less than 1.0 psia. The detailed requirements of this rule are incorporated into the permit. Following is a summary of the requirements:

(1) The permittee shall comply with the standard for volatile organic compounds (VOC) and store petroleum liquids in tanks 186 and 190 as follows:
Since the true vapor pressure of the petroleum liquid, as stored, is equal to or greater than 78 mm Hg (1.5 psia) but not greater than 570 mm Hg (11.1 psia), the storage vessel shall be equipped with a floating roof, a vapor recovery system, or their equivalents. There are no VOC requirements applicable to Tanks 195, 183, 188 and 189 because the stored liquid has a true vapor pressure below 1.5 psia.

(2) The permittee shall comply with the monitoring requirements for tanks 186 and 190 as specified in 40 CFR 60.113. Tanks 195, 183, 188 and 189 are exempt from the monitoring requirements of 40 CFR 60.113 since each stores a petroleum liquid with a vapor pressure less than 1.0 psia.

<u>*Emission Units not Subject to 40 CFR 60, Subpart K:*</u>
The requirements of 40 CFR 60, Subpart K are not included in the permit for storage tanks 179a, 179b, 179c and 173 because each tank's storage capacity is less than the rule applicability threshold of 40,000 gallons, pursuant to 40 CFR 60.110(a).

The requirements of 40 CFR 60, Subpart K are not included in the permit for storage tanks 167, 168, 160, 161, 153, 157, 158, 181, 182, 191, 192, 193, 194, 198, 199, 201, 180, and

180a because these tanks were constructed either prior to the rule applicability date of June 11, 1973 or after May 19, 1978, and there have been no modification or reconstruction approvals issued to the source for these units.

The requirements of 40 CFR 60, Subpart K are not included in the permit for storage tanks 187, 196 and 197. Although these tanks were originally constructed between the rule applicability dates of June 11, 1973 and May 19, 1978, they were later modified after July 23, 1984 and therefore are subject to 40 CFR Parts 60.110b Subparts Kb requirements as discussed in the next section.

The requirements of 40 CFR 60, Subpart K are not included in the permit for storage tank 178 because this tank stores Sodium Hydroxide, which is not a petroleum liquid.

(b) 401 KAR 60:005, Sections 2 and 3(1)(p) incorporates by reference *40 CFR Part 60.110a to 60.115a (Subpart Ka), "Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984"*

The requirements of 40 CFR 60, Subpart Ka are not included in the permit for storage tanks 198, 199, 201, 180, and 180a, all storing petroleum liquids and constructed between the rule applicability date of May 18, 1978 and July 23, 1984, because each tank's storage capacity is less than the rule applicability threshold of 40,000 gallons.

(c) 401 KAR 60:005, Sections 2 and 3(1)(q) incorporates by reference *40 CFR Part 60.110b to 60.117b(Subpart Kb), "Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984"*

Emission Units Subject to 40 CFR 60, Subpart Kb:
Pursuant to Permit No. C-88-129, issued on July 25, 1988, storage tanks identified as 196 and 197 are subject to the requirements of 40 CFR Part 60, Subparts Kb. Storage tank 196 with maximum storage capacity of 426,232 gallons stores crude oil with a vapor pressure of 2.69 psia. Storage tank 197 with maximum storage capacity of 215,964 gallons stores naphtha with a vapor pressure of 9.0 psia.

Pursuant to Permit No. S-97-087, issued on July 28, 1997, the permittee is required to comply with the requirements of Agreed Order DAQ-19141-106 for the storage tank identified as 184, with a storage capacity of 292,151 gallons. Such Agreed Order (and permit) requires the permittee to install and operate primary and secondary seals on tank 184, and to comply with the related requirements pursuant to 40 CFR Part 60, Subpart Kb. These requirements are included in this permit.

Pursuant to Permit No. S-00-082, issued on June 15, 2000, the Division determined storage tank 187 to be subject to the requirements of 40 CFR 60, Subpart Kb. Storage tank 187, with maximum storage capacity of 420,604 gallons, stores heavy gas oil with negligible vapor pressure.
The detailed requirements of this rule are incorporated into the permit. Following is a summary of the requirements:

(1) Storage tanks 196, 197, 184 and 187, each with a design capacity greater than or equal to 151 m^3 shall be equipped with an internal floating roof with the following applicable standards:

(A) A fixed roof in combination with an internal floating roof meeting the following specifications:

(i) The internal floating roof shall rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.

(ii) Each internal floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof:

(aa) A foam- or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal). A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the storage vessel and the floating roof continuously around the circumference of the tank.

(bb) Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be vapor-mounted, but both must be continuous.

(cc) A mechanical shoe seal. A mechanical shoe seal is a metal sheet held vertically against the wall of the storage vessel by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

(iii) Each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents is to provide a projection below the liquid surface.

(iv) Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains is to be equipped with a cover or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use.

(v) Automatic bleeder vents shall be equipped with a gasket and are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(vi) Rim space vents shall be equipped with a gasket and are to be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting.

(vii) Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The sample well shall have a slit fabric cover that covers at least 90 percent of the opening.

(viii) Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover.

(ix) Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.

(2) The permittee shall comply with the Testing and Procedure requirements for each storage tank subject to the rule as specified in 40 CFR 60.113b.

(3) The permittee shall comply with the Reporting and Record Keeping requirements for each storage tank subject to the rule as specified in 40 CFR 60.115b.

(4) The permittee shall comply with the Monitoring of Operations requirements for each storage tank subject to the rule as specified in 40 CFR 60.116b.

(d) 401 KAR 59:050, *New Storage Vessels for Petroleum Liquids*
This rule applies to each storage vessel for petroleum liquids with a storage capacity less than or equal to 151,400 liters (40,000 gallons) that commenced on and after the classification date of April 9, 1972 and before July 24, 1984, and to vessels with a storage capacity less than 40,000 liters (10,567 gallons) that commenced on or after July 24, 1984, when any such vessel is located in either an ozone nonattainment county or located at any other county at a major source of VOC. This rule also applies to vessels with a storage capacity greater than 40,000 gallons that commenced on or after the classification date of April 9, 1972 and prior to July 24, 1984.

(1) Storage tanks 184, 187, 196, and 197 are permitted units reflected in Permit No. O-84-124, issued on February 13, 1987, but with no corresponding applicable rule(s). This notwithstanding, it has been determined during this review that each of these tanks are subject to the requirements of Rule 401 KAR 59:050 since each tank commenced after April 9, 1972 and before July 24, 1984, and has a storage capacity of greater than 40,000 gallons. Each of these tanks store petroleum liquids with a true vapor pressure less than 1.5 psia except storage tanks 196 and 197. Tank 196 stores crude oil with a true vapor pressure of 2.69 psia, and Tank 197 stores naphtha with a true vapor pressure of 9.0 psia.

The above listed storage tanks shall be subject to the following requirements.

(A) Storage tanks 196 and 197 with storage capacity greater than 580 gallons and storing a petroleum liquid with a true vapor pressure greater than 1.5 psia, shall be equipped with a permanent submerged fill pipe. [401 KAR 59:050, Section 3(2)]

(B) Storage tanks 196 and 197, with a storage capacity greater than 40,000 gallons and storing a petroleum liquid with a true vapor pressure greater than 1.5 psia and less than 11.1 psia, shall be equipped with one (1) of the following: [401 KAR 59:050, Section 3(3)]

(i) An external floating roof, consisting of a pontoon-type or double-deck-type cover that rests on the surface of the liquid contents and is equipped with a closure device between the tank wall and the roof edge. Except as provided in paragraph (cc), the closure device is to consist of two (2) seals, one (1) above the other. The lower seal is referred to as the primary seal and the upper seal is referred to as the secondary seal. Each seal is to meet the following requirements:

(aa) The primary seal is to be either a metallic shoe seal, a liquid-mounted seal, or a vapor-mounted seal.

(bb) The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in Section 4(3)(c) of this administrative regulation.

(cc) The owner or operator is exempted from the requirements for secondary seals and the secondary seal gap criteria when performing gap measurements or inspections of the primary seal.

(ii) A fixed roof with an internal floating type cover equipped with a continuous closure device between the tank wall and the cover edge.

(iii) A vapor recovery system which collects all VOC vapors and gases discharged from the storage vessel, and a vapor return or disposal system which is designed to process such VOC vapors and gases so as to reduce their emission to the atmosphere by at least ninety-five (95) percent by weight.

(iv) A system equivalent to those described in paragraphs (i) to (iii) of this subsection as determined by the cabinet.

(C) Storage tanks identified as 184, 187, 196, and 197 shall comply with the Operating Requirements as specified in 401 KAR 59:050, Section 4.

(D) Storage tanks identified as 184, 187, 196, and 197 shall comply with the Monitoring of Operations requirements as specified in 401 KAR 59:050, Section 5.

Emission Units not Subject to 401 KAR 59:050:
The storage tanks identified as 167, 168, 160, 161, 153, 157, 158, 178, 181, 182, 183, 186, 188, 189, 190, 191, 192, 193, 194, and 195 are not subject to the requirements of this rule because each tank commenced before the rule applicability date of April 9, 1972. Storage tank 184 stores heavy gas oil with vapor pressure of 0.1 psia, therefore, none of the

requirements of this rule are applicable.

(e) 401 KAR 61:050, *Existing Storage Vessels for Petroleum Liquids*
This rule applies to each storage vessel for petroleum liquids with a storage capacity of greater than 2,195 liters (580 gallons) that commenced before the classification date of April 9, 1972, and which is located in a county or portion of a county designated ozone nonattainment under 401 KAR 51:101, except marginal nonattainment.

This source is not subject to this rule because it is located in Pulaski County which is designated as attainment for ozone.

Combustion Units

(a) 401 KAR 60:005, Sections 2 and 3(1)(n) incorporates by reference *40 CFR Part 60.100 to 60.190(Subpart J), "Standards of Performance for Petroleum Refineries"*

<u>*Emission Units Subject to 40 CFR 60, Subpart J:*</u>
The requirements of 40 CFR 60, Subpart J, apply to the following emission units because each unit combusts refinery fuel gas and commenced construction or modification after June 11, 1973:

400 HP Continental Boiler (EP1), Crude Distillation Heater (EP2), Crude Distillation Heater (EP21), Gasoline Hydrotreater Heater (EP22), Catalytic Reforming Heater (EP23), Catalytic Reforming Heater (EP24), Catalytic Reforming Heater (EP25), Kerosene Hydrotreater Heater (EP26), Vacuum Tower (EP56), Modified Hydrotreater Catalyst Unit (EP57), and two (2) Indirect Heaters (S187).

The detailed requirements of this rule are incorporated into the permit. Following is a summary of the requirements:

(1) Standards for Sulfur Oxides:
   (A) Pursuant to 40 CFR 60.104(a)(1) and Permit No. S-96-224, issued on June 27^{th}, 1996, the 400 HP Continental Boiler (EP1) shall be fired with fuel gas from reforming of hydrotreated naphtha, or with natural gas, and shall not burn any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10gr/dscf).
   (B) Pursuant to 40 CFR 60.104(a)(1) and Permit No. O-84-124, issued on February 13, 1987, each combustion unit including the Crude Distillation Heater (EP2), Crude Distillation Heater (EP21), Gasoline Hydrotreater Heater (EP22), Catalytic Reforming Heater (EP23), Catalytic Reforming Heater (EP24), Catalytic Reforming Heater (EP25), and Kerosene Hydrotreater Heater (EP26) shall be fired with fuel gas from reforming of hydrotreated naphtha, or with natural gas, and shall not burn any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10gr/dscf).
   (C) Pursuant to 40 CFR 60.104(a)(1), each combustion unit including the Vacuum Tower (EP56), Modified Hydrotreater Catalyst Unit (EP57) and two (2) Indirect Heaters tank 187 (S187) shall be fired with fuel gas from

reforming of hydrotreated naphtha, or with natural gas, and shall not burn any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10gr/dscf).

(2) Monitoring of Emissions and Operations:
A continuous monitoring system (CMS) shall be installed, calibrated, maintained, and operated by the permittee for fuel gas combustion devices subject to 40 CFR 60.104(a)(1). The monitoring unit shall continuously monitor and record the concentration (dry basis) of H_2S in fuel gases before being burned in any fuel gas combustion device. The permittee has already satisfied the initial test requirements pursuant to 40 CFR 60.106, and shall continue to demonstrate compliance with the operation of the installed CMS.

(3) The permittee shall comply with the Reporting and Recordkeeping requirements for each combustion unit subject to the rule as specified in 40 CFR 60.107.

(b) 401 KAR 60:005, Sections 2 and 3(1)(e) incorporates by reference *40 CFR Part 60.40c to 60.48c (Subpart Dc), "Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units"*

The requirements of 40 CFR 60.40c, Subpart Dc, apply to the 400 HP Continental Boiler (EP01) because it was constructed after the rule applicability date of June 9, 1989, and has a maximum design heat input capacity greater than 10 mmBtu per hour and less than 100 mmBtu per hour. However, since this boiler only combusts refinery fuel gas, it is subject only to the record keeping and reporting requirements as specified in 40 CFR 60.48c (a) and (g). The applicable record keeping and reporting requirements are as follows:

The permittee shall record and maintain records for a period of two years of the amounts of each fuel combusted during each month.

(c) 401 KAR 63:002, Section 2, requires affected sources to comply with the applicable Part 63 NESHAP, *40 CFR Part 63.7480 (Subpart DDDDD), "National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters"*

The refinery fuel combustion units are not subject to the requirements of 40 CFR Part 63, Subpart DDDDD, because the refinery is not a major source of HAP emissions. The source has potential emissions of the combination of HAPs and any single HAP of less than 25 and 10 tons per year, respectively.

(d) *401 KAR 59:015, New Indirect Heat Exchangers*

Pursuant to 401 KAR 59:015, Section 1, the requirements of this rule apply to each indirect heat exchanger having a heat input capacity of more than one (1) million BTU per hour and that commenced on or after the applicable classification date defined in Section 2 (3) of the rule. The maximum heat input capacity of each of the following combustion units is greater than the rule applicability threshold. Therefore, 401 KAR 59:015 is applicable to the following combustion units, and the allowable particulate and sulfur dioxide (SO_2) emission limits are included in the permit.

Kerosene Hydrotreater Heater (EP26), and two (2) Indirect Heaters (S187).

Vacuum Tower (EP56), Modified Hydrotreater Catalyst Unit (EP57), and crude distillation heater (EP21) are not subject to the requirements of the rule since these are not classified as *indirect heat exchangers*.

Pursuant to 401 KAR 59:015 and Permit No. S-96-224, issued on June 27, 1996:

(A) Particulate emission rate from the 400 HP Continental Boiler (EP01) shall not exceed 0.3318 lb/ mmBtu.

(B) Opacity from the 400 HP Continental Boiler (EP01) shall not exceed twenty (20) percent.

In addition, the sulfur dioxide emission rate from the 400 HP Continental Boiler (EP01) shall not exceed 1.626 lb/mmbut.

(e) The permittee shall comply with the following particulate, SO_2 and opacity limitations specifically established in the cited permits:

(1) Pursuant to 401 KAR 61:015 and Permit No. O-84-124 (Revised), issued on February 13, 1993:

(A) Particulate emission rate from the Crude Distillation Heater (EP2), Gasoline Hydrotreater Heater (EP22), Catalytic Reforming Heater (EP23), Catalytic Reforming Heater (EP24), Catalytic Reforming Heater (EP25) each shall not exceed 0.614 lb/ mmBtu.

(B) Sulfur dioxide emission rate from the Crude Distillation Heater (EP2), Gasoline Hydrotreater Heater (EP22), Catalytic Reforming Heater (EP23), Catalytic Reforming Heater (EP24), Catalytic Reforming Heater (EP25) each shall not exceed 3.476 lb/ mmBtu.

(C) Opacity from the Crude Distillation Heater (EP2), Gasoline Hydrotreater Heater (EP22), Catalytic Reforming Heater (EP23), Catalytic Reforming Heater (EP24), Catalytic Reforming Heater (EP25) shall not exceed forty (40) percent.

Loading Rack

(a) 401 KAR 60:005, Sections 2 and 3(1)(bbb) incorporates by reference *40 CFR Part 60.500 to 60.506(Subpart XX), “Standards of Performance for Bulk Gasoline Terminal”*

The requirements of 40 CFR 60.500, Subpart XX, do not apply to the loading rack (identified as EP06) because the source does not meet the definition of the *Bulk Gasoline Terminal* as defined at 40 CFR 60.501.

(b) 401 KAR 63:002, Section 3(n) incorporates by reference *40 CFR Part 63.420 to 63.429 (Subpart R), “National Emission Standards for Gasoline Distribution Facilities (Bulk*

Gasoline Terminals and Pipeline Breakout Stations"

The loading rack at the facility is not subject to the requirements of 40 CFR Part 63.420, Subpart R, because the refinery is not a major source of HAP emissions. The potential to emit of any combination of HAPs and any single HAP is less than 25 and 10 tons per year, respectively, therefore the rule does not apply.

(c) Pursuant to Construction Permit No. C-93-126, issued on September 7th, 1993, the maximum loading rate of gasoline shall not exceed 115,000 gallons per day and 17,940,000 gallons per year. However, the source has requested to increase the throughput limit to the maximum throughput of 20,547,844 gallons per year. Emission calculations for the loading rack are based on this maximum gasoline throughput and the increase will not change the permit level and violate any other rules.

(d) 401 KAR 59:046, *Selected new petroleum refining processes and equipment*

The requirements of this rule are not applicable to this source because it commenced prior to the classification date of June 29, 1979, and this source is not a major source of VOC nor is it located in a county (Pulaski) designated nonattainment for ozone under 401 KAR 51:010.

(e) 401 KAR 59:101, *New Bulk Gasoline Plants*

The requirements of this rule are not applicable to this source because it commenced prior to the classification date of June 29, 1979, and this source is not a major source of VOC nor is it located in a county (Pulaski) designated nonattainment for ozone under 401 KAR 51:010.

(f) 401 KAR 61:055, *Existing Loading Facilities at Bulk Gasoline Terminals*

The permittee is not subject to this rule because the loading facility at this source was determined by the Division to be a *New Bulk Gasoline Terminal*, pursuant to Permit No. C-93-126, issued on September 7th, 1993, as discussed above. The requirements for a *New Bulk Gasoline Terminal* were previously established at 401 KAR 59:099, which has been repealed and replaced with the requirements of 401 KAR 60:005 (40 CFR 60, Subpart XX).

(g) 401 KAR 61:056, *Existing Bulk Gasoline Plants*

The permittee is not subject to this rule because the source is located in Pulaski County which is designated as attainment for ozone.

(h) 401 KAR 61:137*, Leaks from existing petroleum refinery equipment*

The permittee is not subject to this rule because the source is not located in a county (Pulaski) designated nonattainment for ozone under 401 KAR 51:010.

(i) 401 KAR 63:031, *Leaks from Gasoline Tank Trucks*

The permittee is not subject to this rule because the source is located in Pulaski County which is designated as attainment for ozone.

Oil/Water Separator

(a) 401 KAR 60:005, Sections 2 and 3(1)(nnn) incorporates by reference *40 CFR Part 60.690 to 60.699(Subpart QQQ), "Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems"*

Pursuant to 40 CFR 60.690(a)(1), the provisions of this subpart apply to affected facilities including an oil/water separator and drain system constructed or modified after the rule applicability date of May 4, 1987. This rule does not apply to the oil water separator and drain system at the refinery since each was constructed before the rule applicability date of May 4, 1987.

(b) 401 KAR 59:095, *New oil-effluent water separators*

The requirements of this rule are not applicable to this source because it commenced prior to the classification date of June 29, 1979, and this source is not a major source of VOC nor is it located in a county (Pulaski) designated nonattainment for ozone under 401 KAR 51:010.

(c) 401 KAR 61:045, *Existing oil-effluent water separators*

The requirements of this rule are not applicable to this source because it is not a major source of VOC nor is it located in a county (Pulaski) designated nonattainment for ozone under 401 KAR 51:010.

Equipment Leaks

(a) 401 KAR 60:005, Sections 2 and 3(1)(fff) incorporates by reference *40 CFR Part 60.590 to 60.593(Subpart GGG), "Standards of Performance for Volatile for Equipment Leaks of VOC in Petroleum Refineries"*

Pursuant to 40 CFR 60.590, the provisions of this subpart apply to refinery equipment constructed or modified after the rule applicability date of January 4, 1983. As defined under 40 CFR 60.591, the affected refinery equipment includes each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. For the purposes of recordkeeping and reporting only, compressors are considered equipment.

(1) The permittee shall comply with the following standards:

(i)	40 CFR 60.482-1	Standards: General
(ii)	40 CFR 60.482-2	Standards: Pumps in light liquid service
(iii)	40 CFR 60.482-3	Standards: Compressors
(iv)	40 CFR 60.482-4	Standards: Pressure relief devices in gas/vapor service
(v)	40 CFR 60.482-5	Standards: Sampling connection systems
(vi)	40 CFR 60.482-6	Standards: Open-ended valves or lines

(vii)	40 CFR 60.482-7	Standards: Valves in gas/vapor service and in light liquid service
(viii)	40 CFR 60.482-8	Standards: Pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and connectors
(ix)	40 CFR 60.482-9	Standards: Delay of repair
(x)	40 CFR 60.482-10	Standards: Closed vent systems and control devices

(2) The permittee may elect to comply with the following standards:

(i)	40 CFR 60.483-1	Alternative standards for valves--allowable percentage of valves leaking
(ii)	40 CFR 60.483-2	Alternative standards for valves--skip period leak detection and repair

(3) The permittee may apply to the Division for a determination of equivalency for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart. In doing so, the permittee shall comply with requirements of 40 CFR 60.484 (Equivalence of means of emission limitation).

(4) The permittee subject to the provisions of this subpart shall comply with the Test Methods and Procedures requirements as specified in 40 CFR 60.485.

(5) The permittee subject to the provisions of this subpart shall comply with the Recordkeeping and Reporting Requirements as specified in 40 CFR 60.486 and 60.487, respectively.

(b) 401 KAR 63:010, *Fugitive Emissions*

Pursuant to 401 KAR 63:010, Section 1, the requirements of this rule apply to an apparatus, operation, or road which emits or may emit fugitive emissions provided that the fugitive emissions from such facility are not elsewhere subject to an opacity standard within the administrative regulations of the Division for Air Quality. Therefore, 401 KAR 63:010 is an applicable rule for the equipment leaks.

Entire Source

(a) 40 CFR 64, *Compliance Assurance Monitoring (CAM)*
The requirements of 40 CFR 64, *Compliance Assurance Monitoring*, are not included in the permit for any emission unit at this source because no emission unit at this source has an uncontrolled PTE particulate matter at greater than 100 percent of the applicable major Part 70 threshold. Therefore, pursuant to 40 CFR 64.2 (a), the requirements of this rule are not included in the permit.

(b) 401 KAR 63:002, Section 3(w) incorporates by reference *40 CFR Part 63.640 (Subpart CC), "National Emission Standards for Hazardous Emissions from Petroleum Refineries"*

The refinery is not subject to the requirements of 40 CFR Part 63.640, Subpart CC, because the source is not a major source of HAP emissions. The potential to emit of the combination of HAPs and any single HAP is less than 25 and 10 tons per year, respectively, therefore the rule does not apply.

(c) 401 KAR 63:002, Section 3(ggg) incorporates by reference *40 CFR Part 63.1560 (Subpart UUU), "National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units"*

The refinery is not subject to the requirements of 40 CFR Part 63.1560, Subpart UUU, because the source is not a major source of HAP emissions. The potential to emit of the combination of HAPs and any single HAP is less than 25 and 10 tons per year, respectively, therefore the rule does not apply.

(d) 401 KAR 61:145, *Existing petroleum refineries*

Pursuant to 401 61:145, Section 1, the requirements of this rule apply to fuel gas combustion devices commenced before June 11, 1973. All the fuel gas combustion devices at the source commenced after the classification date of June 11, 1973, therefore, this rule does not apply.

(e) 401 KAR 63:020, *Potentially hazardous matter or toxic substances*

The requirements of this rule apply to each facility which emits or may emit potentially hazardous matter or toxic substances as defined at 401 KAR 63:020, Section 2, provided such emissions are not elsewhere subject to the provisions of the administrative regulations of the Division. This source is regulated by various regulations as discussed within this Statement of Basis, including federal New Source Performance Standards. This notwithstanding, this rule is included in Section B of the permit for Facility Components, whereby the requisite leak detection monitoring, and other provisions of the permit, are considered to comply with this rule.

Flare

(a) 401 KAR 63:015, *Flares*

Pursuant to 401 KAR 63:015, Section 1, the requirements of this rule apply to each flare. Therefore, 401 KAR 63:010 is an applicable rule for the flare (EP04) at the refinery. The permittee, shall not cause, suffer, or allow the emission into the open air of particulate matter from the flare which is greater than twenty (20) percent opacity for more than three (3) minutes in any one (1) day.

(b) 401 KAR 60:005, Sections 2 and 3(1)(n) incorporates by reference *40 CFR Part 60.100 to 60.190(Subpart J), "Standards of Performance for Petroleum Refineries"*

Pursuant to 40 CFR 60.104(a)(1), the combustion of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from the Sulfur oxide standard.

Cooling Towers

Pursuant to Permit No. S-96-183, issued on May 6, 1996, the cooling tower water in the two (2) cooling towers shall not contain chromium-based water treatment chemicals.

Sulfur Removal Unit

(a) 401 KAR 60:005, Sections 2 and 3(1)(n) incorporates by reference *40 CFR Part 60.100 to 60.190(Subpart J), "Standards of Performance for Petroleum Refineries"*

One (1) Sulfur Removal Unit, consisting of sulfa treat columns and a Sodium Hydro Sulfide (NaHS) Unit, identified as EP55 is not subject to the requirements of 40 CFR Part 60.100, Subpart J because the Sulfur Removal Unit at this facility is not a *Claus Sulfur Recovery Unit* as defined in 40 CFR 60.101 (Definitions).

SOURCE STATUS:

(a) This existing source, a refinery which is one of the twenty-eight (28) listed source categories under 401 KAR 51:017, is not a major stationary source for PSD review because the potential to emit of any regulated pollutant is less than 100 tons per year.

(b) Pulaski County is designated as attainment for the 8-hour ozone standard and VOC and NOx, as regulated ozone precursor pollutants, are emitted at a rate less than 100 tons per year. No other criteria pollutant is emitted at a rate of 100 tons per year or more. Therefore, the existing source is not a major stationary source under prevention of significant deterioration of air quality (PSD), 401 KAR 51:017.

EMISSION AND OPERATING CAPS DESCRIPTION:

(a) Pursuant to Operation Permit No. O-84-124 (Revised), issued on February 13, 1987, the total annual processing/production rates shall not exceed the following limitations on a twelve (12) consecutive month basis:

(1) Crude Oil: 2,242,800 barrels per twelve (12) consecutive month period;
(2) Gasoline: 427,200 barrels per twelve (12) consecutive month period;
(3) Naphtha: 358,848 barrels per twelve (12) consecutive month period; and
(4) Kerosene: 142,400 barrels per year twelve (12) consecutive month period.

(b) To preclude the applicability of 40 CFR Part 63.640 (Subpart CC), "National Emission Standards for Hazardous Emissions from Petroleum Refineries", total annual source-wide emissions shall not exceed the following specific limitations on a twelve (12) consecutive month basis:

(1) Volatile organic compound (VOC) emissions shall not equal or exceed 90 tons per twelve (12) consecutive month period;
(2) Emissions of any single hazardous air pollutants (HAP) shall not exceed 9 tons per

twelve (12) consecutive month period; and

(3) Emissions of combined hazardous air pollutant (HAPs) shall not exceed 22.5 tons per twelve (12) consecutive month period.

PERIODIC MONITORING:

To demonstrate compliance with the source-wide emissions limits, the permittee shall monitor the VRU controlling VOC and HAP emissions from the loading rack and screening values (SV) for each type of component under the LDAR program. Detailed requirements for monitoring can be found under the *Comments* Section of the SOB and *Sections B and D* of the permit.

Monitoring requirements for other emission units including storage tanks, indirect heat exchangers, flare, sulfur removal unit are also listed in detail in the corresponding *Section B* of the permit.

OPERATIONAL FLEXIBILITY:

None

CREDIBLE EVIDENCE:

This permit contains provisions which require that specific test methods, monitoring or recordkeeping be used as a demonstration of compliance with permit limits. On February 24, 1997, the U.S. EPA promulgated revisions to the following federal regulations: 40 CFR Part 51, Sec. 51.212; 40 CFR Part 52, Sec. 52.12; 40 CFR Part 52, Sec. 52.30; 40 CFR Part 60, Sec. 60.11 and 40 CFR Part 61, Sec. 61.12, that allow the use of credible evidence to establish compliance with applicable requirements. At the issuance of this permit, Kentucky has not incorporated these provisions in its air quality regulations.